

low levels. Figure 3 shows that while WTI was trading at a premium of more than \$23 to Mexican Maya Blend in mid 2008, the differential has narrowed considerably and in 9 January 2009 Mexican Maya was trading at a discount of less than \$7 per barrel. This can also be explained by the fact that most OPEC production cuts are usually concentrated on heavy crudes.

In short, WTI's dislocation has had serious implications across the various crude oil markets, resulting in unusual price differentials. These effects, however, do not imply that the local market is not functioning well. On the contrary, price movements are efficiently reflecting the local supply-demand conditions in Cushing. The main problem is that when localised conditions become dominant, WTI can no longer reflect the supply-demand balance in the USA, nor act as an international benchmark for pricing the millions of barrels of oil imported into the USA.

“the link of the WTI price to oil prices in international markets can be dictated by infrastructure logistics”

Conclusions

While the media often focuses on the sharp swings in oil price, there have been some interesting feedbacks unfolding in the term structure of oil prices with wide consequences on the international pricing system, financial investment, inventories and OPEC behaviour. These feedbacks are not new to the oil market, but the current environment seems to have amplified price distortions. While the market will eventually succeed in eliminating these distortions and market dislocation, the fact remains that these reinforcing feedbacks seem to have become more common in recent times. This suggests that we need to get prepared for some more sharp irregularities in months to come.

LNG Trading: Overview and Challenges

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The Need for LNG

In the 27 countries of the European Union, growing demand for gas over the next decade or so will create a need for new import projects covering 140 bn m³ p.a. – needs which are not going to be covered by Russian and Norwegian imports alone. Diversification is required to avoid a singular dependency, which is not conducive either to supply reliability or to an acceptable price level. This is why international corporations are looking to North Africa, West Africa, the Middle East and Asia for new sources of supply. That being so, there are five countries – Iran, Qatar, United Arab Emirates, Nigeria and Algeria – which now number in the world's Top Ten in terms of natural gas reserves. However, it is from these countries that the delivery of gas is usually made by ship, in the form of LNG (liquefied natural gas), and not by pipeline.

Definition of LNG and Costs

The worldwide LNG market is basically divided into two regions: the Pacific Basin and the Atlantic Basin. The LNG chain involves a liquefaction plant with several ‘trains’ situated in the producer country; marine transport with LNG tankers; and regasification terminals in the receiving country where the LNG is temporarily stored in tanks before being regasified and fed into the pipeline network.

With investments well into the US\$-billions, the liquefaction plant represents the biggest cost factor within the LNG chain. The LNG chain initially involves natural gas being refrigerated to approximately -162 °C, at which point it condenses to a liquid and takes up only 1/600 of its original volume. For a large-scale plant, then, as currently being built in Qatar with a planned capacity of 7.8 mn t LNG p.a. (≈10 bn. m³ p.a.), investments of between US\$900 and 1500 per t LNG p.a. are required or anything between US\$7 and 12 bn in total. In comparison, a regasification terminal of the same scale and constructed for US\$0.8–1.2 bn comes over as relatively affordable. For an LNG tanker with a load capacity of, say, 265,000 m³, you have to reckon between US\$250 and 290 mn. At the time of writing, the going charter rate is between US\$45,000 and US\$70,000 a day.

In the 1990s, the LNG industry was able to achieve considerable cost reductions based on improved efficiency, design innovations, greater professional project management and, in particular, economies of scale. The first LNG projects in the 1960s had a capacity of 0.5 mn t LNG p.a. whereas the liquefaction plants of today are being put up for 7.8 mn t LNG per annum. Plus, the possible load capacity of the LNG tankers has grown from approximately 30,000 m³ to 265,000 m³, another reason why specific costs have gone down substantially. All the same, the engineering, procurement & construction (EPC) costs for liquefaction plants have shot up over recent years. This was largely due to the rising cost of raw materials and other input materials, the low number of suitable contractors and the shortage of engineers in this specialist field.

Meanwhile, it has emerged that energy consumptions along the LNG chain are actually much lower than hitherto widely assumed –

- liquefaction approximately 7%,
- shipping approximately 0.15% per day and
- regasification approximately 1.5%.

All in all, energy consumptions can usually be kept to below 10%, correlated of course to the technology deployed and, in particular, to actual shipping distance.

Pipeline versus Ship

The debate, about what distance between production and receiving country leads to an entire LNG chain having an advantage over pipeline transport, is as old as the LNG industry itself.

The solution to this problem (which may at first seem trivial) is a complex one. Thanks to high fixed costs and low variable costs, the LNG cost line is flat whereas the pipeline cost line is very steep. In the literature, a point of intersection between the pipeline line and the LNG line is frequently hypothesised at a distance of 3000–5000 km. This oversimplified view is, in our opinion, not tenable.

Over the course of a given period, the gridlines can shift and strongly correlate with capacity or economies of scale. Furthermore, pipeline costs are dependent on territorial contingencies (onshore, offshore, mountain ranges) not to mention that port and passage fees – through the Suez Canal, for instance – can affect pricing. Also the transport distances via pipeline and LNG deviate typically. However, there exist other crucial reasons more of a strategic nature in favour of LNG, namely:

- no transit countries, and thus the avoidance of protracted political and commercial negotiations;
- relatively straightforward capacity extension;
- technical necessity, since a hook-up to a pipeline network is practically impossible due to geological peculiarities (e.g. Japan's island position); and
- flexible routing, and thus the exploitation of arbitrage possibilities.

This, in sum, underscores the necessity of always weighing up all the criteria with regards to various options when taking an investment decision.

Price Formation on the LNG Market

In contrast to the situation with crude oil, the LNG market has not yet seen the development of a globally valid price for the market: there are price differences in the USA, Europe and Asia. There are also certain differences in the pricing of LNG both on the spot market and in long-term contracts.

Prices on the spot market are usually set in the short term for individual or for a few consignments and, are often based on Henry Hub¹ or NBP² for the Atlantic and JCC³ for the Pacific Basin.

As a rule, however, long-term LNG prices are linked either to crude oil and/or refined oil products or to price developments with NBP and/or Henry Hub. This means that linkages to the NBP and oil products are prevalent for the European market, that Henry Hub governs pricing

in the USA and that the crude oil pricing known as JCC governs the Asian area. The pronounced rise in demand for LNG over recent years compared to supply has led to an increase in the general LNG price and thus to an increase in the asking price for long-term LNG contracts. It remains to be seen which impact liquefaction capacity that comes on-stream in the next years will have on long-term prices.

Nevertheless, LNG prices also come under the influence of other interdependencies. For instance, price development with infrastructure in the whole LNG sector and price developments on markets for alternative fuels such as heating oil, coal and uranium also play their part in pricing strategies.

However, with more fluidity of LNG trade being on the way, we will also see a convergence of world-wide LNG prices.

Supply–Demand Balance

The biggest producing countries on the supply side in 2007 were Qatar (approx. 38 bn m³), Indonesia (29 bn m³), Malaysia (28 m³), Algeria (22 bn m³) and Nigeria (21 bn m³). Due to their geographical position, these countries are clearly well poised to deliver to certain regions – i.e. Indonesia and Malaysia deliver to the Pacific Basin while Algeria supplies first and foremost Spain and France.

The position of Qatar and other Middle East countries lends them a special significance in the LNG business: this region can serve both the Atlantic and the Pacific Basins. The LNG producers of the Middle East can therefore react flexibly to regional price differences and generate additional profit in the process. Thanks to the production capacities currently available, this region can influence market balance and, as a consequence, the price level.

Qatar is expected to achieve LNG output of approximately 78 bn m³ in 2010. Its significance can only grow in the future. By 2015, Qatar with over 98 bn m³ LNG p.a. will be far and away the world's largest producer of LNG. Nigeria will be second with an output of 45 bn m³, and Australia will be the third largest supply country.

The demand side nowadays is dominated by the Pacific Basin with imports of 126 bn m³ p.a., the biggest importers being Japan (86 bn m³) and South Korea (30 bn m³). In the Atlantic Basin (89 bn m³), today's biggest receiving countries are Spain and Portugal with 34 bn m³ combined and the USA with 20 bn m³ per annum.

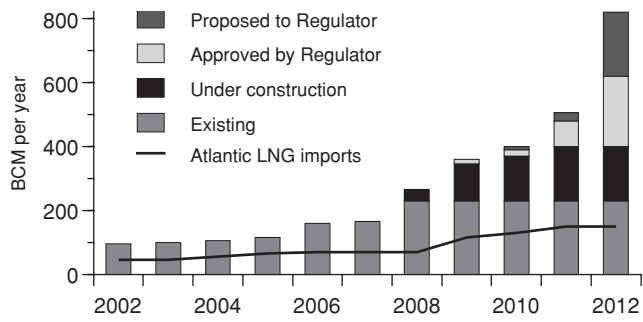
That inequality between Pacific Basin and Atlantic Basin is set to balance out by 2015. Asia has generally been the premium-price market of choice for sellers, but there will be simply insufficient demand in this region to absorb the increase in supply. Indeed, a preponderance of deliveries to the Atlantic Basin seems likely after 2015. This development is based on the rising demand predicted for the USA where LNG consumption was just a few months ago expected to grow beyond 100 bn m³ p.a. in the future. On the one hand, such an increase in US natural gas and thereby LNG consumption could arise from the introduction of a stringent carbon dioxide trading regime in the USA and a consequent increase in gas power plants; on the other hand the need

1 Henry Hub is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX). It is a point on the natural gas pipeline system in Erath, Louisiana.

2 NBP = National Balancing Point, a virtual trading location for the sale and purchase of natural gas in the UK.

3 JCC: Japan Crude Oil Cocktail = average price of crude oil imported by Japan

Figure 1: Atlantic Basin Regas Capacity vs. Atlantic LNG Imports 2002–2012



Note: Regasification capacity for approved and proposed terminals is based on project sponsor dates. LNG import outlook 2009–2012 based on Global Fissures Scenario

Source: CERA – Cambridge Energy Research Associates, 2008

for US gas imports might be lower as a consequence of increased gas production from shales over the next few years and lower general demand due to the economic crisis. The UK too will play a role in balancing the equation, with its forecast growth of 40 bn m³ per annum.

The complexity of the LNG landscape is also growing considerably. In fact, some of the producing countries such as Qatar and Egypt have opted for moratoria while Indonesia appears to be having supply problems. Altogether, we can speak of an increasing presence in Africa and the Middle East on the part of NOCs who are now faced with a choice of using their gas reserves for the LNG export market or holding on to them for domestic requirements. That being the case, IOCs are faced with the real challenge of gaining access to gas reserves in order to feed future LNG projects.

Shipping

If the additional LNG quantities expected for the future are to be dealt with, investments in LNG fleets are going to be necessary. Although 300 LNG tankers already plough the oceans, a further 100 are on order. At the same time, we can assume an increase in ship size from today's standard of 145,000 m³ to 265,000 m³ (Q_{max}). The first Q_{max} carrier with a capacity of 265,000 m³ was delivered to Nakilat, Qatar's LNG shipping arm, in August 2008.

Regasification

Regasification terminal projects are gaining in importance for Europe and the USA in particular since they act as an anchor-point for a diversified portfolio. Each project has its own individual obstacles to overcome – the availability of LNG, approvals, regulations, access to third-party customers and the need to guarantee reliable operations for several users. Additionally, just like liquefaction projects, regasification terminal projects faced significant price increases of up

to 75% with capacity charges reaching 70 UScents/mmBtu compared to 40 UScents/mmBtu in 2002. Nevertheless, a good number of projects have been successfully implemented globally over the last few years.

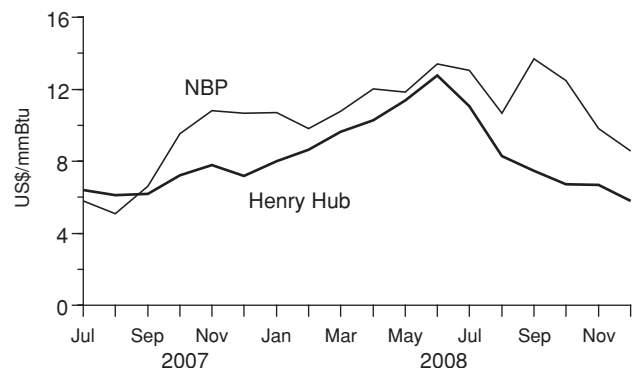
Anyone taking a close look at the regasification capacities available until 2010 will realise that they outstrip expected supply quantities considerably (see Figure 1). The rationale that persuades corporations to secure themselves capacities at the terminals lies in being able to exploit the arbitrage possibilities provided by surplus capacity – ‘arbitrage’ being defined here as the exploitation of regional price differentials on the LNG market. Consequently the booking of regasification capacity is considered more and more an option payment to place gas in a particular market than an investment linked to fixed volumes. In this way, LNG tankers can be dispatched in the short term either to American or European regasification terminals and corporations can profit from price fluctuations. However, there is a difference between physically existent capacity and available capacity, meaning that access (or not) to a regasification terminal for new players often acts as a barrier to getting on to the market.

When it comes to operating the arbitrage business lucratively, the *sine qua non* is an adequate margin between the purchase of the LNG and the sale of natural gas on the target market, a margin which covers not only the transport costs but also the charge levied on an unused slot in another regasification terminal. ‘Slot’ here is defined as the right of an LNG supplier to unload a tanker at a regasification terminal and subsequently have the LNG temporarily stored, regasified and fed into the natural gas pipeline grid. To optimise the use of regasification capacity and still be able to benefit from arbitrage opportunities some Atlantic Basin players established swap arrangements allowing both parties involved to utilise regasification capacity on both sides of the Atlantic.

In addition to the regasification of LNG some operators of LNG terminals install equipment for the reloading of LNG which will then be transported to other locations.

As Figure 2 illustrates, there can be good possibilities for arbitrage between the USA and Britain. From September

Figure 2: Example of Arbitrage Opportunities at NBP and Henry Hub in 2007/08



2007 until the end of October 2008, for example, it was profitable for LNG players to reroute deliveries destined for the USA to Britain and thus make additional profit. However, in the case of 2008 spot prices in the Pacific Basin exceeded price levels in the UK. Consequently LNG cargoes were diverted to Asia, and UK regasification terminals still remained idle.

Thanks to the formal oil-gas price linkage in place on the European mainland and to NBP notation in the UK, arbitrage possibilities also exist in Europe. However, these possibilities will recede with the construction of pipeline connections (such as the Balgzand Bacton Line and the Interconnector) between Britain and the European continent. What is more, via the Langed Pipeline, Norway is able in the short term to either decrease or increase supplies to the UK and also benefit from temporarily higher NBP prices. In effect, peak prices can be shaved, at least partly, and arbitrage possibilities can be contained.

Spot Trading and Short-term Trading

Apart from regasification terminal availability, the exploitation of arbitrage possibilities is also boosted by the growth in spot trading and short-term trading. The spot market alone now accounts for approximately 15% of the total LNG market, which corresponds to a trebling of that share since 2000. In 1997, the share taken by short-term trading was very low. Yet the spot market is not a mature liquid market. Spot transactions are still primarily organised within existing supply chains. It will take some time before short-term transactions are as routine as with the oil business. Before the global financial crises in summer 2008, we could observe international banks becoming active on the LNG spot trading scene.

Let us give one example of how player intervention on the spot market can be significantly influenced by fluctuations in a given supply situation in a given region. When, as the result of an earthquake in Japan on 16 July 2007, a TEPCO nuclear power plant had to shut down, the shortfall in power supplies was compensated for by increasing the use of gas-fired power plants. However, to guarantee the gas supplies then required, the Japanese power supply companies stepped up their activities on the spot market and so bought in 15 additional LNG deliveries until summer 2008. That jump in demand had a clear effect on spot market prices. With the collapse of Japanese nuclear capacity and with the high demand for LNG in Asia anyway, it became all the more difficult for other world regions – such as the USA and Europe – to buy in spot cargos.

Peak prices were also seen in China during the summer months in 2008. High natural gas demand for air conditioning, but also for the summer Olympics caused a natural gas shortage in China. Consequently LNG prices of over 20 US\$/mmBtu had to be paid.

Particularly as a consequence of the growing spot market the swap potential will continue to grow. A swap describes an agreement between two LNG players where the vessel of one player is satisfying the delivery obligation of the

other and vice versa. Thereby the players aim to shorten the travel durations of their respective vessels which leads to the reduction of shipping costs and an increased availability of their vessels. For example a vessel leaving Algeria for Japan and at the same time another vessel enroute from Australia to France could be rearranged in a way that the Algerian cargo would be heading to France and the Australian cargo would be sent to Japan. Since 2005 swappable volumes increased from 0.42 bn. m³ p.a. to 9.5 bn m³ in 2007 with huge worldwide potential for the future.

The availability of spot volumes in the Atlantic Basin is expected to increase at least until 2010 with liquefaction capacity from e.g. Northwest Shelf Train 5, Sakhalin 2, Yemen LNG, Tangguh and Qatargas's 2 and 3 coming on-stream in 2009/10 adding around 90 bn m³ per year. With the Pacific Basin being well supplied with LNG at the same time volumes will be forced to flow into the Atlantic Basin thereby increasing liquidity and reducing pricing on the spot market. However, the availability of long-term contracts will remain constrained as barely any tenders for new projects are expected.

Conclusion

LNG can contribute to closing any gaps that may arise on the European energy market and, similarly, by creating greater diversification for the supply and demand countries as well as improve supply security all round.

The high prices in the Pacific Basin complicated the purchase of LNG quantities under competitive conditions for players in the Atlantic Basin. This was a situation exacerbated by the virtually exploding demand for LNG deliveries and the delays with liquefaction and regasification projects, delays caused by the shortage of suitable contractors and labour. As a consequence of the economic turmoil and the demand reduction, especially in Asia, more spot cargoes are nowadays heading towards Europe. The North American LNG market acts as a sink for residual demand.

Demand for LNG is set to grow by 7% annually between 2008 and 2015 – i.e. to about 180 mn t per annum. Just in Europe, the LNG share of gas volume will increase from today's 10% to nearly 20% in 2020.

On today's current market, which is still predominantly a sellers' market, international players will have a distinct advantage over regional actors since the global players are obviously better poised to meet producer expectations with regard to serving different markets. In addition, the dominant sellers' market will further weaken, as the increase in supply of up to 300 bn m³ p.a. should make more competitively priced LNG available.

An increasing globalisation of LNG flows is likely due to companies' strategic positioning, the development of flexible LNG portfolios and pricing arbitrages. The spot market too will gain in significance and surpass its current 15% share of the market as a whole. Arbitrage as well as swap possibilities will increase as a consequence, even if these approaches are vulnerable to physical restrictions such as shipping distance, gas quality and market access.